Measures for transition to an expanded and highly renewable electricity system – summary of submissions

MAY 2024

MINISTRY OF BUSINESS, INNOVATION & EMPLOYMENT
HĪKINA WHAKATUTUKI

Te Kāwanatanga o Aotearoa
New Zealand Government

Online: ISBN 978-1-991143-45-7

May 2024

Contents

Purpose

1. This report summarises key themes from the submissions received on the *Measures for transition to an expanded and highly renewable electricity system* discussion document.

Background

2. In August 2023, the Ministry of Business, Innovation and Employment (MBIE) opened public consultation on the *Measures for transition to an expanded and highly renewable electricity system* discussion document.

3. We received 80 written submissions on the discussion document. The submissions reflect the view of a wide range of interested stakeholders across academia, iwi, consumer groups, generators, retailers, and industrial users. A full list of submitters is included in Annex One.

4. The discussion document explored approaches to ensure New Zealand's electricity system is affordable, reliable, and resilient while we transition to an expanded and more highly renewable system. As shown by Table 1 below, key issues explored were grouped into growing renewable generation, competitive markets, networks for the future, responsive demand and smarter systems, and whole of system considerations.

Table 1: Overview of *Measures for transition to an expanded and highly renewable electricity system* discussion document

		The part covers:
Part 1	**Growing Renewable Generation**	Ensuring sufficient renewable generation is built and that fossil fuel generation will be replaced in a way that maintains security, reliability and affordability, including ensuring sufficient firm capacity during transition. Also considers the role of large-scale flexibility to provide demand response.
Part 2	**Competitive Markets**	Competition issues that may arise in the electricity market during the transition away from fossil fuels and increasing reliance on hydro with storage for firm capacity.
Part 3	**Networks for the Future**	How we ensure sufficient transmission and distribution investment to support a larger share of renewable electricity generation and greater reliance on electricity. Includes considering whether regulator objectives adequately reflect government sustainability goals.
Part 4	**Responsive Demand and Smarter Systems**	Issues relating to increased distributed flexibility including opportunities to utilise smarter systems that will improve electricity system reliability, resilience, and affordability.
Part 5	**Whole of System Considerations**	Whether there is a role for more coordination across the electricity system as a whole and reviews the need for prioritisation by government.

5. The discussion document was published as part of a package of consultation documents on New Zealand's energy transition – the *Gas Transition Plan Issues Paper*, the *Interim Hydrogen Roadmap*, the *Implementation and design of a ban on new fossil-fuel baseload electricity generation* and the *Developing a Regulatory Framework for Offshore Renewable Energy*. Summaries of submissions for the other consultations can be found on the MBIE website.

6. This document is a summary of the submissions MBIE received on *Measures for transition to an expanded and highly renewable electricity system*, including some of the key themes and issues raised by submitters. It draws on the comments made by submitters but does not reflect every comment made by each submitter.

Overview of submissions

Key themes from submitters

7. High level key themes reflected the diversity of both issues and submitters, and in general acknowledged that a changing environment for participants justifies focus on whether settings remain fit for purpose.

8. In summary, submissions highlighted that:

   - Ensuring energy affordability through the transition is key and will be difficult to achieve given the level of investment required.
   - There are differing views on the need for measures to support new renewable generation such as contracts for differences and power purchase agreements. There was strong agreement that getting the resource consenting framework is important enabler of the transition.
   - The role of thermal generation through energy transition is important but uncertain, in particular the role of gas as a transitional fuel (gas supply is also uncertain).
   - There are broad concerns about whether current network investment regulatory models are sufficiently flexible and suited towards supporting electrification and decarbonisation.
   - Participants see real barriers to connection to distribution networks, from both load and generation, particularly in relation to the upfront costs of connection.
   - There are mixed views on whether the wholesale market is competitive, and some related concerns raised about retail competition.
   - The risks of early versus later transmission investment have changed and it's important that transmission access does not end up an impediment to investment in renewables generation. Whether any changes are required to existing regulatory frameworks received mixed views.
   - Better government direction and support is needed to support harnessing the potential of distributed energy resources and flexibility markets developing.
   - In general, stable "macro" policy settings are important to produce investor confidence.

Summary of Iwi/Māori views

9. Five submitters represented iwi and/or hapū groupings. While these submissions covered issues raised across the consultation documents, the following were key themes relevant to this discussion document:

- The transition to more renewable energy future is important to iwi/hapū.
- Iwi/hapū see the Crown as having a key role in leading this transition and as an "enabler". One submitter suggested it wanted to see a more ambitious, urgent, and well-coordinated plan from government, another also referenced the time-sensitive nature of measures to support the transition, and another suggested the Crown may need to play a central planning role to get things built where the best resources exist and use all of its "levers" during the transition.
- Iwi/hapū expect the Crown to meet its Te Tiriti o Waitangi obligations and consider existing settlements. Iwi/hapū expect to work in genuine partnership with the Crown and have aspirations of ongoing engagement with the Crown and MBIE. They expect to not just be "consulted" on things that affect them but also to be actively involved with planning and decision-making and have real opportunities to benefit from the transition, including commercial and economic opportunities.
- Related to the above, a regional focus is important to iwi/hapū. Submitters often emphasised the importance of specific types of existing generation and infrastructure, and also future opportunities, relevant to the whānau and communities in their own rohe. For at least one submitter, this aligned with explicit expectations of rangatiratanga over local land, water and resources.
- Iwi/hapū want to ensure intergenerational, multi-dimensional view of issues including cultural and environmental matters. Submitters emphasised that the transition needs to be managed to avoid negative impacts on their people and the environment / natural world (Te Taiao). One submitter saw maintaining energy security and energy equity, and protecting the health and wellbeing of whānau and communities, as important and as a wider influencer of positive outcomes. Another noted that people needed to be at the centre, and not just decarbonisation and increased energy production.

Summary of submissions by chapter

PART 1: Growing renewable generation

CHAPTER 2: ACCELERATING SUPPLY OF RENEWABLES

10. Approximately 50 submissions were received on issues discussed in Chapter 2. Some issues discussed in relation Chapter 2 also crossed over with competition-related matters discussed in more detail in Chapter 6 (workably competitive electricity markets).

Submitters agreed additional measures may be needed to accelerate renewable supply

11. Submitters generally agreed that significant investment in renewable generation is needed, or is expected, and that such investment needs to be enabled or supported by electricity market settings and by the broader policy and regulatory environment measures. However, submissions differed on the reasons why additional measures were needed, and the nature of measures needed.

Some submitters suggested measures need to improve investment uncertainty

12. Some submissions focused on a perceived lack of policy and market certainty to support investment decisions for new renewables. For example, several submitters claimed a lack of stable government strategy on macro-market drivers (including carbon pricing and gas exploration settings) has contributed to generation investment uncertainty, particularly from the offshore investor market. Some submissions suggested these uncertainties have also constrained investment in "firm" resources that could support new intermittent renewables (discussed in more detail the Chapter 3 summary below).

13. To address this, some submissions proposed generic forms of government support, including development of a vision and a pathway to a fully renewable system. Others called more specifically for greater certainty regarding gas exploration and a transition plan, the NZ Battery Project, emission trading scheme (ETS)/carbon pricing, and renewable energy targets to ensure an attractive investment climate.

Submitters had mixed views about whether competition-related measures were important

14. A key tension between submitters was whether analysis should focus on the sufficiency of the pipeline of renewables alone, or also ensuring low barriers to entry for non-incumbent generators to build new renewables. Many submitters said the current market gives incumbent and vertically integrated generator-retailers (known as "gentailers") too much market power, and that generation investment by new entry developers is challenging without additional measures to reduce the entry costs. However, many submitters also noted that plenty of generation is being investigated and planned without such measures – and that further measures could therefore be distortionary and should only be considered if there is evidence insufficient generation is forthcoming.

15. Those concerned with incumbent generators' market power suggested that, without extra measures, new generation development could largely remain the domain of existing incumbents who have access to renewable based dispatchable generation - and in particular, those participants that own and operate hydro generation with storage. Some also said the existing generation market structure incentivised incumbents to perpetuate only incremental growth in capacity to keep prices high by maintaining a perpetual state of near shortage. These submitters suggested measures were needed to disrupt this model by enabling entry

from independent developers, which could lead to a step change in the scale of generation development that could reduce wholesale prices.

16. Submitters suggested measures could focus on overcoming new entrant developers' need for commercial offtake agreements and/or a retail customer base to underwrite generation investments – these being advantages which incumbent gentailers possess and use to leverage their own investments. Measures could be developed to stabilise new entrant developers' revenue, or otherwise reduce investment risk and support access to debt finance.

Submitters said there was a lack of suitable risk management tools to support new renewables

17. Related to the above discussion, many submitters also discussed the difficulty of non-gentailers accessing suitable risk management arrangements – such as standardised financial hedging contracts, including shaped or flexible hedge contracts – to secure offtake agreements needed for intermittent renewable projects.

18. Some suggested the government could underwrite such arrangements to enable new entrants to invest. One submitter suggested gentailers could be required to provide peak demand and price cap products. However, others thought this issue could be addressed through introduction of a capacity market, or other measures to reward firm or flexible capacity that could support further investment in intermittent renewables.

Many submitters were concerned with network capacity and planning processes

19. Many submitters agreed that planning regulation adds unwarranted time and cost to generation and network development, and is a barrier to investment. Many also thought unwarranted delays, uncertain timing, and high costs of transmission and distribution network investment were a barrier to renewable generation investment.

20. Many submissions referred to the need for more streamlined and more supportive planning processes under the Resource Management Act 1991 and Conservation Act 1987, both for generation projects and for the associated transmission and distribution infrastructure. Some also extended this to roads and the port infrastructure that will be needed for offshore wind farm development.

21. Some submitters suggested that, because of the slow pace of transmission investment, there was a high probability that new renewable generation projects will be consented and built before there will be is sufficient transmission capacity available to service 100% of the generation output. To avoid this, some submitters favoured "renewable energy zones" (REZs), or other measures for the government to ensure grid capacity.

CHAPTER 3: ENSURING SUFFICIENT FIRM CAPACITY DURING TRANSITION

22. Approximately 45 submissions were received on issues discussed in Chapter 3.

Submitters agree firming is needed, but there is disagreement about how to support this

23. Submitters all supported the need for more firming generation, but were divided over whether the energy only market will provide this or whether additional capacity incentives or schemes are needed – either now, or in the future. Submitters were also divided over whether, if support is needed, that support should be only for renewable technologies, should support thermal generation, or should be technology agnostic.

A range of submitters supported an ongoing role for thermal firming during the transition

24. A range of submitters, including developers of renewable generation, argued that there was a role for thermal firming to help support the energy transition, although specific views on that role varied. Some submitters noted a range of renewable generation coming to build stage, but a paucity of new firming to replace soon to be retired thermal generation plant.

25. One submitter suggested that both gas and a diverse set of other supply and demand-side options would be an important enabler of the transition, to get to a more renewable energy supply while maintaining system reliability and affordability, including reducing the need for extra grid capacity just for peaks.

26. Several submitters considered gas fired or thermal generation may need (financial) support in future to manage security of supply and to support renewable generation, but argued that this support was not yet needed. One submitter, however, argued against any form of government intervention in future unless there was clear evidence of market failure, but if intervention was to happen then government could support investment by removing the risk of future government policy or regulatory changes materially negatively impacting the economics and overall viability of such investments.

27. If support was needed, potential options cited by submitters could include some form of capacity market or mechanism, while others pointed to the UK model to incentivise thermals during the transition, while using CfDs to promote renewables and batteries. One submitter argued that the costs of running a capacity market are unlikely to outweigh its benefits. In contrast, another submitter acknowledged that while capacity payments may bring unintended consequences they argued that these consequences are less than the counterfactual of doing nothing as hoping the market will deliver is a high risk strategy. Another submitter suggested that if government did intervene, the model should be structured to prevent future changes in policy affecting the economic viability of investments made in reliance on this.

28. Separately, one submitter argued that the current pricing mechanism that pays all generators the marginal price should be reviewed despite the disruption that would result to the current market mechanisms as it pushes up prices to consumers. It also commented that payment for firming generation and demand side load reduction should be considered.

Many submitters supported firming from renewable only sources (with no role for thermal)

29. Many submitters supported the need for new firming, and for this support to be provided by government but only if it was provided via renewable options. Submitters made a range of points in support of or relevant to this position, examples being that:

- there are no compelling reasons to support existing or new fossil fuel gas fired generation (baseload or peak), and support on the basis of affordability is short-term and misguided
- use of hydro generation should be changed so that it is used for firming renewable generation, rather than as baseload generation – and that this approach may require a “rationalisation” of hydro assets
- continuing policies supporting gas fired or thermal generation keep market prices high
- interventions should consider both firming and peaking, and longer term storage – and that Battery Electric Storage Systems (BESS), unlike a pumped hydro scheme, will not address longer term storage issues

- interventions would also need to be carefully designed (e.g., support for long term storage could significantly shift the balance in terms of utility scale versus household solar).

Some submitters supported both renewable and thermal firming or were technology neutral

30. A number of submitters supported measures to enhance firming but were either neutral on its form, or supported both fossil fuelled and renewable options. For example:

    - One offshore wind developer argued government-facilitated price stabilisation measures could support firming / storage assets in the same way as for new renewable generation, and that measures to support both BESS and green-molecule based storage are warranted.
    - One gentailer saw existing and new gas fired peaking as the least cost, most emissions friendly option for support the renewable transition, but considered regulatory certainty about the role of gas was the only support needed.
    - Another gentailer supported an ongoing role for some fast start peaking generation in the foreseeable future but not a capacity market. It argued that future demand response will eventually displace gas peakers as emissions prices increase and large-scale demand response becomes more economic.
    - One electricity distribution network (EDB) suggested demand response will need to be carefully managed when thermal peaking starts to phase out. It also argued that consumer energy resources or CER (e.g., rooftop solar, batteries, electric vehicles (EVs) and smart devices) should be optimised to play a role in short term firming, and that this will require CER owners to be incentivised to participate, including through appropriate pricing and retailer incentives for storage.

CHAPTER 4: MANAGING SLOW-START THERMAL CAPACITY DURING THE TRANSITION

31. Approximately 30 submissions were received on issues discussed in Chapter 4.

Submitters had mixed views about support for slow-start thermals to manage an orderly transition

32. There was no clear agreement between submitters on whether further measures are needed to support slow-start thermal as we transition to a more highly renewable system, to avoid the risk of an unmanaged exit of thermal generation. However, some submitters who argued against further measures also indicated limited support for an obligation for thermal generators to notify in advance where they intend to retire plant.

Submitters in favour of extra measures focused on security of supply risks

33. Submitters speaking in favour of, or supporting, intervention polices generally noted the need to support system security over the transition. Comments across different submitters included that:

    - arguments for measures will carry more weight if it becomes apparent that thermal plant is necessary to ensure ongoing security of supply
    - the size of thermal plant creates significant risks, as there could be an unplanned material reduction in system resources to balance energy capacity, voltage and frequency – and so a standby ancillary service will become critical to provide additional flexible resources and reduce operational capacity risks in a more intermittent system

- there are conflicting objectives with thermal plant – on the one hand there is an expressed requirement to "phase down" existing thermal plants, and on the other measures may be needed to retain thermal plants to avoid risks to security of supply
- retirement of some thermal will see more concentration in the remaining thermal plant, and the ability to set the price, which also flows through to the value for hydro
- notice periods will help manage phase down
- however, notice periods could also have a direct value impact for market participants, including for staff retention and maintenance expenditure
- there may be a need to place thermal plant into a strategic reserve in the future, which could include models such as "Thermalco" proposed earlier by Contact Energy, to support the transition.

Submitters against further measures thought these were unneeded and could impose costs

34. A few submitters rejected the need to support thermal retirement. Comments included that:

- the evidence for further measures is mixed – this would impose a collective "insurance" cost on the market and Genesis, which owns the bulk of slow start thermal not due for retirement, will need this to meet its customers' demand and compete with hydro during peaks
- this could be used as ploy to retain thermal longer than needed and to keep spot prices high – whereas massive investment in rooftop solar could be the best option to avoid supply shortages
- a capacity market or strategic reserves creates risks of higher prices and oversupply.

CHAPTER 5: THE ROLE OF LARGE-SCALE FLEXIBILITY

35. Approximately 35 submissions were received on issues discussed in Chapter 5.

Submitters agree industrial demand response will be an important part of the energy system

36. All submitters emphasised the value of demand response in helping to balance supply and demand and its increasing value as the percentage of renewable electricity increases and thermal generation declines. Submitters indicated the importance of the Electricity Authority's real time pricing work to facilitate greater use of demand response.

The value of avoided business production is a key issue for participation in demand response

37. Submitters generally agreed that a key issue for whether businesses participate in demand response was the impact of reducing, or delaying, production of their goods versus the benefits of lowering electrical demand. However, submitters varied considerably over what was a sufficient incentive to deliver the value from demand response – and in particular, whether the benefit of lowering demand should simply be the avoided electricity cost, or whether some additional incentive was required.

There are mixed views on additional measures to incentivise greater demand response

38. Submitters expressed mixed views on whether the market by itself provides sufficient incentives for large-scale demand response. In general, larger industrial submitters argued for additional payments, especially for longer-term demand-response over weeks or months.

39. Some submitters argued that market or contractual arrangements between suppliers and consumers were sufficient to enable significant demand response, such that no further

incentives were needed. One gentailer, for example, argued that bilateral contracts are fully capable of meeting the specific requirements of any large consumer to provide demand response, while another submitter expressed a similar view.

40. A contrary view was presented by many submitters, arguing that additional incentives were needed to bring forward material volumes of demand response. Some for example argued that:

- participants that bid demand response into the market should be paid the final price for that trading period on the volume of demand response dispatched
- the ancillary market needs to be considered, and that load reduction should be remunerated as for generation as it has the same value to the system.

41. Various points were made by different submitters about market dynamics, including that:

- the dispatchable demand model (e.g., avoided purchase cost) is not attractive to large industrial users because it does not provide a material benefit sufficient to balance lost production
- aside from some long-term energy arrangements with flexibility included, there is very little demand response developing in the commercial and industrial space outside of large individual bespoke contracts
- it is unclear whether demand response solely through market developments under real time pricing would be sufficient.

Relationship with distributed flexibility

42. Other submitters noted the synergy between demand response and distributed generation and storage (batteries), and argued that these CER-enabled responses should have access to similar mechanisms and incentives in the market.

PART 2: Competitive Markets

CHAPTER 6: WORKABLY COMPETITIVE ELECTRICITY MARKETS

43. Approximately 40 submissions were received on issues discussed in Chapter 6. Separately, a number of submitters made competition-related points in their submissions on Chapter 2 (accelerating the supply of renewables), which are discussed above.

Submitters saw a risk of increasing market concentration among hydro-resourced gentailers

44. As discussed in the comments above on Chapter 2, most submitters agreed that the expected decline in thermal generation could increase market concentration in the flexible segment of the wholesale market, lessening competition.

Some submitters thought market concentration was already happening and required intervention

45. Some (e.g., independent retails and major energy users) thought this scenario was already playing out and said the Electricity Authority's wholesale competition investigation in 2021 provided evidence of that. These submissions generally favoured immediate interventions to address the problem, although some considered more analysis was warranted to determine the extent of the problem.

Other submitters saw increased market concentration as only theoretical and opposed intervention

46. Some submitters (most gentailers) considered that the prospect of increasing market concentration was merely a theoretical possibility. They suggested no interventions to address a potential problem should be considered unless or until there is clear evidence there really is a problem that can be remedied. They generally agreed with the conclusions and actions taken by the Electricity Authority following its wholesale competition review.

Some submitters opposed interventions until there was proof of market power abuse

47. Some submissions noted that a degree of market power will always exist in any electricity market, no matter what changes might be made to the market structure. They suggested that market power is not a problem unless it is abused, and the best policy is to monitor market conduct and take remedial action only if there is clear evidence of abuse, and if the cost of remedy is lower than the cost of any abuse.

PART 3: Networks for the future

CHAPTER 7: A TRANSMISSION SYSTEM FOR GROWTH

48. Approximately 35 submissions were received on issues discussed in Chapter 7.

Submitters noted that the risks of early versus later transmission investment have changed

49. Almost all submitters agreed that the balance of risk between investing too early and investing too late has shifted in recent years. Reasons for this included the need for sufficient grid capacity to support electrification for net zero by 2050, and the divergence between the time needed to build new transmission (which has gotten longer) compared to new generation. Submissions suggested Transpower will likely need to strengthen the core grid to respond to the changing mix of generation sources and location of new renewable resources, as well as changing demand centres.

50. Submissions emphasised the importance of transmission not ending up an impediment to investment in renewables generation. Historically, in an environment of low demand growth, new generation was primarily added to the system as large hydro or thermal assets. There were few actors in the generation space, and transmission upgrades were largely planned and developed in parallel with these generation assets. The risks of underinvestment previously were mainly security and reliability.

51. These risks remain – but in addition there are now also the risks that delayed transmission build out creates a barrier to us meeting emissions reductions targets and/or connecting new renewable generation (which should put downward pressure on wholesale prices). From a global perspective, there are also supply chain risks, as international demand for transformers and other grid equipment increases to support global decarbonisation.

Submissions agreed that planning laws needed to be more enabling

52. To support more timely build out of the national grid, submitters agreed on the importance of an enabling environment for resource management consenting – to try shave time off the end-to-end process and align with generation investment timeframes.

Timely access to the grid is critical for some generations sources (such as offshore wind)

53. Specifically for offshore wind developers, submissions suggested that guaranteed and timely grid access is critical. Developers require certainty regarding transmission and grid

connection to achieve final investment decision. This point was also echoed by others, for an independent solar developer.

Submitters acknowledged possible overbuild, but some queried whether this was a timing issue

54. There was recognition that 'overbuild' is still a real and significant costs to consumers and therefore scrutiny and robust regulatory processes remain necessary. However, some argued that stranded asset risk, in this current environment, is likely to be a timing issue – i.e., that this may result in underutilised capacity for a period, rather than complete redundancy.

55. In support of this, some supported development of new financing mechanisms that recognise future demand is a matter of "when" rather than "if". Related to this, a few submitters commented that first-mover disadvantage or FMD (i.e., high upfront costs when Transpower builds above the actual needs of the connecting party, on the basis of anticipated future demand) was still an issue that is slowing down electrification.

Submitters expressed mixed views on the need for regulatory change and Transpower's processes

56. Submitters expressed mixed views on whether changes are required to the Commerce Commission's regulatory framework under Part 4 of the Commerce Act 1986, or whether it is sufficiently flexible.

57. Likewise, submitters varied in their views on the state of Transpower's connection queue. Some submitters said that recently implemented changes were good and sensible, while others said the waiting time remained too long and more needed to be done to get rid of 'opportunistic applications'. Other comments suggested the large number of connection queries make it difficult for developers to understand where future capacity needs to be built, or where existing capacity exists.

Some groups challenged the traditional one-way power system supported by transmission

58. A small number of consumer groups suggested that the traditional centralised model (big power stations with lots of transmission) is outdated and that focus should be on more distributed generation – particularly rooftop solar. This would allow more generation to occur where electricity is consumed, avoiding losses and expensive transmission.

CHAPTER 8: DISTRIBUTION NETWORKS FOR GROWTH

59. Approximately 40 submissions were received on issues discussed in Chapter 8.

Submitters agreed that existing regulation was a barrier to efficient network investment

60. Submissions indicated a widespread concern that the existing regulatory settings will not support the scale of investment electricity distribution businesses (EDBs) need to make in the next regulatory period (2025 – 2030). This concern was expressed strongly from EDBs themselves, but also a range of other submitters – with very few submitters suggesting only incremental change is needed.

61. Concerns ranged across both the suitability of the statutory framework regulating the return EDBs can make as monopoly providers (Part 4 of the Commerce Act 1986), and the Commerce Commission's regulatory processes to implement this framework, to meet accelerated investment needed for rapid electrification of homes and businesses, and for increased resilience in the face of a changing climate.

62. Common concerns included that:

- there is a lack of flexibility to change EDBs' recoverable revenue during their five-year regulated period
- the Commission's approach is too focused on historical data rather than less certain future growth
- the regulatory model disincentivises opex solutions as against capex investment
- regulatory decisions do not adequately take account of sustainability objectives
- "whole of system" thinking is not integrated into decisions around network investment under the current framework.

63. Some EDBs also raised concerns with Commission's recent draft, and forthcoming, decisions on the next five-year regulatory period starting in 2025 – highlighting, for example, how back-ending cashflow may reduce funding for network investments, and a lack of adequate funding for innovation.

Non-EDBs saw issues with the cost of connections and first-mover disadvantage, while EDBs did not

64. A large number of non-EDBs expressed concerns with the high costs of connecting to networks, and how this could be a barrier to electrification or new generation – especially where new connections involve anticipatory build, the costs of which a new connector could have to bear (leading to first-mover disadvantage or FMD). This included electric vehicle (EV) charge point operators (CPOs), who cited this and variability between EDBs as a key barrier to electrification of light transport. Non-EDB submitters also cited wide variations in the extent to which EDBs pass on connection costs: (a) all or largely upfront or over a longer period via lines charges, and/or (b) solely to the connecting customer or also to others (cross-subsidising).

65. However, most EDB submitters suggested both that FMD was not a significant issue and that their costs of connection were reasonable – suggesting that significant network connections can be expensive by their nature and the "costs are the costs". At least one EDB did, however, concede that the regulatory framework is not geared to reward anticipatory network build.

66. EDBs submitted against the idea of regulating costs of connection, arguing they needed discretion to apply connection policies meeting the unique circumstances of their network (e.g., given their particular financing needs, customer types, and geographical spread) and that this would undermine the idea of more efficient cost-reflective pricing. At least one EDB argued for transparency first (e.g., of costs), before more direct interventions.

67. EDBs also argued against applying pricing principles similar to those in Part 6 of the Electricity Industry Participation Code 2010 (Code) – saying this would add complexity and would not address FMD or costs issues – as EDBs would still be entitled to charge reasonable costs. There were mixed views for a Part 6 approach from non-EDBs. A number supported this idea or something similar, with particularly strong support from the representative body for CPOs, but others thought this might give the appearance of a solution without actually addressing key concerns.

68. A good number of non-EDBs and EDBs supported some form of government-backed financing to help support anticipatory build of network capacity, potentially for national or regionally significant connections, to overcome high upfront costs and/or FMD. A large range of other options were also suggested to address these issues, such as creating renewable energy zones, exploring capped-costs for different connection types, better transparency of

connection costs, competition for network upgrade work, or adoption of a FMD approach similar to that in the Transmission Pricing Methodology.

Submitters agreed that non-price considerations could be barriers to connection of new demand

69. Submissions indicated a high degree of consensus that non-price barriers – in particular, limited availability of information regarding capacity and inconsistency of processes – are affecting the speed and difficulty of new connections.

70. Several submitters pointed to a lack of lack of transparency around capacity constraints and utilisation affecting connection decisions and cost. Submitters suggested this should be clearer and more accessible – for example, via information disclosure on the worst performing feeders and/or GIS data on network load and asset utilisation.

71. Some submitters also raised more general concerns that connection processes are often opaque and/or can involve unnecessary delays.

Submitters agreed that Code processes for connecting distributed generation need reviewing

72. Few submissions suggest there is a fundamental problem with processes for connection of distributed generation, but there are a range of "niggles" with Part 6 of the Code (governing distributed generation connections) and support for its review. Key themes are that Part 6 has remained largely static, despite the nature of connections growing from smaller scale distributed generation to significant utility scale that may not have originally been envisaged.

73. EDBs did not necessarily have any concerns technically with connections, but did generally support a review of Part 6 of the Code, some noting challenges with:

    - the thresholds for different connection processes in Part 6 (including timelines and requirements), given differences between smaller and larger scale connections
    - charging for larger-scale connections (e.g., that it can be difficult to apportion recovery of network cost for distributed generation export to these customers).

74. Some non-EDBs suggested possible concerns with the cost of connecting, although EDBs suggested these connections can simply be expensive by nature. Non-EDBs also pointed to possible delays affecting investments, and a lack of clear guides or standards for large distributed generation and EDB published constraint management policies.

EDBs oppose more regulated distribution pricing, while many non-EDBs support this

75. EDBs oppose prescriptive distribution pricing, saying that the Electricity Authority's scorecards are working, and that differences between networks means EDBs should retain discretion to adopt pricing appropriate to them. They also raise concerns that this could undermine cost-reflective pricing.

76. However, there is support for more prescriptive pricing from a number of non-EDBs, with a smaller number concerned that this will not be effective. Non-EDBs also point to a lack of transparency across EDBs as to how distribution pricing is established and costs allocated across customers.

77. Although other factors affect cost reflective pricing (e.g., the LFC phase out), EDB submitters were concerned that retailers are failing to pass through price signals and point out many retailers are failing to use actual time-of-use consumption data. However, retailers submitted that they should have wide discretion in how they respond to pass on distribution tariffs, and suggested that consumers are not yet ready for highly price-reflective tariffs.

Most submitters thought there was insufficient regulatory coordination and alignment

78. Most submitters that responded suggested there is a lack of coordination and/or transparency across regulatory actors. Only a small number suggested there was adequate coordination. A number of submitters also specifically noted an unhelpful regulatory overlap between the jurisdiction of the Electricity Authority and the Commerce Commission.

79. Submitters suggested a variety of options for better regulatory alignment, such as:

- better transparency and coordination from the Council of Energy Regulators
- the development of an energy strategy with industry
- more focus on "whole of system" planning
- amendments to the regulators' objectives
- proposals for a single energy regulator and/or new energy-specific ministry.

CHAPTER 9: IS THE GOVERNMENT'S SUSTAINABILITY OBJECTIVE ADEQUATELY REFLECTED FOR MARKET REGULATORS?

80. Approximately 30 submissions were received on issues discussed in Chapter 9.

Most submitters thought sustainability objectives should be reflected in regulators' decision-making

81. The majority of submitters on this question did not think existing regulator objectives were sufficient in relation to the energy transition, or that it was sufficiently clear that they would be sufficiently taken into account.

82. A few submissions from EDBs acknowledged the Commerce Commission's position with respect to the permissive consideration in section 5ZN of the Climate Change Response Act 2002 (CCRA). But, they further commented that this consideration was too subjective in terms of how much weighting should be given to climate change and emissions reduction objectives in section 5ZN of the CCRA.

83. Of those who supported strengthening direction, some of the reasoning included that:

- emissions reduction is consistent with the long-term benefits for consumers
- climate change is a long-term challenge that New Zealand (and the world) will grapple with, making it appropriate to reflect this in regulatory objectives
- the 2050 net zero target is legislated
- if the Electricity Authority and Commerce Commission are expected to support decarbonisation and emissions reduction in line with net zero 2050, then that mandate should be explicit.

84. Of those who supported strengthening climate change objectives of regulators, there was not a consensus on whether a government policy statement (GPS) or legislative change would the most appropriate vehicle. One submitter suggested that a GPS could be issued, monitored for effectiveness, with consideration of legislative change following that.

85. There were submitters who thought the status quo was sufficient and appropriate for market regulators. A few submissions pointed towards the 2018-2019 Electricity Price Review which considered this question, but which ultimately concluded that the addition of a climate focused objective could pull the regulator in too many directions.

PART 4: Response demand and smarter systems

CHAPTER 10: INCREASING DISTRIBUTED FLEXIBILITY

86. Approximately 45 submissions were received on issues discussed in Chapter 10.

Many submitters want more government leadership to support CER and distributed flexibility

87. Many submitters felt that government should show leadership and support existing collaborative industry workstreams on distributed flexibility that are already underway. Submitters identified a long list of areas where government could take action to help grow and develop flexibility markets. The most frequently identified areas to support collaboration were innovation funding for collaborative trials integrating distributed energy resources or consumer energy resources (CER) such as rooftop solar, batteries, EVs and smart devices and use of distributed flexibility, support for existing industry processes (including co-funding), and addressing regulatory barriers (high level suggestion).

88. Another theme was that government should prioritise addressing systemic barriers to uptake of non-network solutions (NNS), including addressing availability of data, and visibility of CER and regulation of smart devices – especially smart capability for EV charging (regardless of form). Some submitters also noted support for Government to accelerate regulatory workstreams including maintaining legislative and regulatory alignment with modern electrical standards (such as AS/NZS 4777) and a review of voltage thresholds for low voltage networks set in the Electricity (Safety) Regulations 2010.

89. The majority of submitters also supported setting out a future structure of a common digital energy infrastructure (to allow trading of distributed flexibility) supporting co-ordinated action, but highlighted capability building through collaborative trials and learning by doing is needed first and there are other priorities (e.g., those in paragraph 88 above).

90. There were mixed views of whether Government should provide co-funding for EDBs to support procurement of NNS, and varied views about whether lack of uptake was due to lack of smart data and regulation of smart devices, or due to limitations with the regulatory model determining EDB revenues (Part 4 of the Commerce Act 1986).

Most submitters thought that dynamic operating envelopes would be important for flexiblity

91. Most submitters thought that dynamic operating envelopes (DOEs) or a similar concepts would be important to flexibility services development. Some submitters fell that the concept should be explored but noted that the detail of DOE design and impacts on consumers must be carefully considered in the New Zealand context before determining if this type of mechanism is required.

Submitters broadly supported approach to smart device standards and cyber security, but had mixed views on automated device registration

92. Submitters were broadly supportive of the approaches to smart device standards and cyber security outlined in the document. Many submissions from EDBs highlighted the importance of mandating smart EV charging capability regardless of form, to help limit peak demand growth on their networks. Mandates could more generally require EV owners to have smart charging capability with the choice of whether this is provided as a feature of their vehicle or by an external charger. This may be difficult to implement but could be linked to the registration of the vehicle.

93. There were mixed views on whether government should provide funding for automated device registration, with support for doing or exploring this from around half of submitters.

Others cautioned against automated device registration right now – for example, on the basis that the Electricity Registry could be repurposed for this, that registration would be ineffective without other measures, or because of a view that commercial incentives can instead be used to encourage collection of this information.

There were mixed views on the need for extra measures to grow use of flexibility rewarding tariffs

94. There was mixed support for extra measures to grow use of retail tariffs rewarding flexibility. Gentailers and some EDBs cautioned against further measures – in general suggesting that the retail tariffs were available and/or would develop naturally in response to consumer demand as the Low-Fixed Charge (LFC) is phased out.

95. However, a range of other submitters of different backgrounds either supported further measures or thought they should be explored. Suggestions covered a variety of possible measures – for example, feed in tariffs, measures to reward consumers for lowering consumption, measures to support aggregators bidding CER into the wholesale market, subsidies for CER devices, and requirements for retailers to tell consumers about their "best plan". Lack of pass through of temporal cost reflective distribution prices by retailers was noted as an issue by a small number of submitters, noting the need for "simple value propositions and set and forget solutions for customers with regulation that protects the customers best interests."

A majority of submitters supported measures to encourage investment in battery storage

96. There mixed views on whether there is a need for measures targeted to encourage investment in battery storage. Some submitters supported measures to create more investment certainty for local battery storage, with some supporting doing so in a way that would not have negative distributional effects (i.e., that would allow poorer as well as richer households to benefit). Submitters suggested a range of options to support uptake, including subsidies, low-interest loans and pricing incentives that reward flexibility. Submitters also noted Government could provide support for batteries in specific situations for example resilience support for impacted communities or on Government housing.

97. Some submitters thought that focus should be on developing flexibility rewarding tariffs and pricing instead of targeted support for batteries. Some disagreed with further government measures on the basis that this could deter lower-cost grid-scale investments, that existing market mechanisms are available (i.e., banks' low interest loans), and that this could reward a particular technology rather than letting the market decide the best solution.

Submitters supported equitable access to solar and batteries

98. Submitters showed strong support for targeted support to allow low-income households to access the benefits of solar and battery. Various factors would need to be considered though (e.g., how to offer access to solar and batteries for renters, and the need to address other barriers to the development of flexibility). Some submitters however expressed concern with the idea of subsidies to address up-front costs, noting the availability of low-interest bank loans and that this could be inefficient and lead to higher overall costs for consumers.

Most submitters supported measures to reduce 'soft costs'

99. A majority of submitters supported measures to reduce 'soft costs' and agreed government had a role in enabling a 'smart systems' and improving network resilience. Considerations for reducing soft costs included the role of cybersecurity, the role of government in supporting industry capacity and training, and regulatory settings for CER.

Most submitters supported looking at a review of critical data availability

100. Most submitters supported further regulatory steps to look at data availability, suggesting this was necessary given the importance of data access to help support CER and efficient networks in future. However, a smaller number did not support a review, suggesting that previous barriers to access were now being overcome, including through the Electricity Authority's coming work programme as well as a future consumer data right.

PART 5: Whole-of-system considerations

CHAPTER 11: SETTING PRIORITIES AND IMPROVING COORDINATION

101. Approximately 60 submissions were received on issues discussed in Chapter 11.

Submitters had varied views on priority areas to support the energy transition

102. Submitters varied widely on what they thought should be priority areas for the government to support the energy transition. Some of key points which were mentioned by multiple submitters include:

- having fit-for-purpose regulatory environments to enable investment to support electrification, including resource management (across generation, transmission and distribution), the Overseas Investment Act 2005 for offshore investors, price-quality path regulation for distribution networks, as well as out-of-date regulations such as the New Zealand Electrical Code of Practice for Hamonic Levels (NZECP36)
- developing a New Zealand Energy Strategy, with some submitters saying this is led by whole-of-system thinking
- supporting the establishment of an offshore wind sector in New Zealand
- supporting businesses to decarbonise, such as support for new electrode boilers or more reasonable connection costs
- sector regulators have work programmes and these should continue
- supporting development of a smarter and more flexible system, beginning with access to consumption and electricity quality data for the low voltage network to improve the visibility and support flexibility services.

Submitters supported coordination across the system to drive outcomes, but suggestions varied

103. Submissions varied in terms of what gaps in coordination or information people would like to see filled. Some of the key themes included:

- a desire to see closer coordination amongst central government and regulatory agencies in policy and decision-making
- some submitters, who are part of the group, suggested the Energy Sector Framework can help with coordination and collective action
- a few submitters noted the need to ensure linkages with local interests, such as iwi, councils and economic development agencies.

Submitters had mixed views on the value of renewable energy zones

104. There were generally split views on the renewable energy zone (REZ) concept in New Zealand. Many submitters supported the concept of a REZ being explored further exploration in a New Zealand context. This included from some offshore wind developers supporting exploration of a REZ in the Taranaki region, a few of whom also noted that such a REZ would need to encompass more than transmission considerations and extend to other enablers, such as port infrastructure and quicker consenting pathways. A few submitters who supported further exploration, noted a word of caution to not simply import the Australian model.

105. A few submitters noted that a REZ model is just one way of solving first-mover disadvantage (FMD) and there are other ways. A few submitters pointed out that Transmission Pricing Methodology has mechanisms to address FMD. Others thought that it was not sufficient.

106. One developer suggested that REZs should not be priority now while there is existing grid capacity in the near-term. Further out, it suggested that "mini-REZs" could be an effective away to collaborate between developers, consumers and Transpower.

107. Those that did not support the REZ concept generally argued that it moves towards a centralised model for generation investment which results in an agency picking winners, that open access to the national grid is a key enabler of competition in generation investment, and that this model generally risks distorting investment incentives.

Submitters varied greatly on the balance of outcomes they wanted to see during the transition

108. Submissions were highly varied with respect to the balance of outcomes as we transition to a more renewable electricity system. Points below provide a sample of the breadth and insight of submissions:

- The focus on each of the aims can be expected to shift over time (it's contextual), particularly as the market transition to 100% renewables. The focus should be on reliability in the near-term given winter peak capacity pressures. The World Energy Council index shows New Zealand is falling on the security measure.
- Regarding affordability, this is best achieved through focusing on efficiency and offering low-cost options, with wider welfare policy supporting equity.
- All three limbs of the energy trilemma are important and balancing them is difficult. However, ensuring that no New Zealanders are pushed into energy poverty must be a priority.
- Energy efficiency remains an important part of the equation.
- Distributed renewable generation should be supported, as this targets all three limbs of the energy trilemma.
- Sustainability should be a bottom-line given the legislated targets but the balance between affordability and reliability are a trade-off that customers must determine.

Annex One

List of submitters

Submitter	Type of organisation
Auckland Transport	Local Government
Auckland University	Academic
Aurora Energy	Distribution Network
BlueCurrent	Metering Company
BlueFloat Energy	Offshore Wind Developer
Canterbury University	Academic
Carbon and Energy Professionals NZ	Industry Organisation
Community Energy Network	Non-government Organisation
Consumer Advocacy Council	Consumer Advocate
Contact Energy	Generator-Retailer
Drive Electric	Industry Association
Electra	Distribution Network
Electric Kiwi	Retailer
Electric Power Optimization Centre	Academic
Electricity Networks Aotearoa	Industry Organisation
Enel X Asutralia Pty Ltd	Energy Consultancy
Energy Link	Energy Consultancy
Energy Resources Aotearoa	Industry Association
Energy Sector Framework	Industry Association
Entrust	Distribution Network (Trustees)
Environment & Conservation Organisations of NZ INC.	Non-government Organisation
Electricity Retailers' Association of New Zealand	Industry Association
Flex Forum	Industry Association
Flick Electric	Retailer
Fonterra Co-Operative Group Limited	Industrial
Genesis Energy	Generator-Retailer
Geoff Bertram	Individual
GNS Science	Academic
Greater Wellington Te Pane Matua Taioa	Local Government
Greymouth Petroleum	Upstream Developer
Helios	Generator
Horticulture New Zealand	Industry Association
Independent Electricity Generators Association	Industry Association
Independent Retailers Group	Industry Association
Infrastructure New Zealand	Industry Association
Intellihub	Metering Company
Lodestone Energy	Generator
Lyttelton Energy Transition Society	Non-government Organisation
Major Electricity Users' Group	Industry Association
Manawa Energy	Generator
Mercury	Generator-Retailer

Meridian Energy	Generator-Retailer
Murihiku Regeneration	Hapu
National Energy Research Institute	Non-government organisation
New Zealand Energy Certificate System (NZECS)	Energy Consultancy
New Zealand Geothermal Association (NZGA)	Industry Association
New Zealand Green Building Council	Industry Association
New Zealand Manufacturing Alliance (NZMEA)	Industry Association
New Zealand Steel	Industrial
Ngā Iwi o Taranaki	Iwi
Northern Energy Group	Industry Association
Nova Energy	Generator-Retailer
OMV	Upstream Developer
Orion	Distribution Network
Parkwind	Offshore Wind Developer
Perception Consulting	Energy Consultancy
PowerCo	Distribution Network
PowerNet	Distribution Network
Public Service Association	Union
Schema Consulting	Energy Consultancy
SolarZero	Solar PV provider
Straterra	Industry Association
Taranaki Mayoral Forum	Local Government
Taranaki Offshore Partners	Offshore Wind Developer
Te Rūnanga o Ngāi Tahu	Iwi
Te Rūnanga o Ngāti Mutunga	Iwi
Te Waka	Economic Development Agency
Toitū Envirocare	Energy Consultancy
Transpower	System Operator/ Transmission Grid Owner
Unison and Centralines	Distribution Network
University of Waikato	Academic
Vector	Distribution
Venture Taranaki	Economic Development Agency
Waikato Tainui	Iwi
Wellington Electricity	Distribution Network
West Coast Regional Council	Local Government
Windy Quarry Zealandia	Offshore Wind Developer
Wise Response Society Inc.	Non-government Organisation
Z Energy Limited	Retailer

Annex Two

Recap of questions

PART 1: GROWING RENEWABLE GENERATION	
1.	Are any extra measures needed to support new renewable generation during the transition? Please keep in mind existing investment incentives through the energy-only market and the ETS, and also available risk management products. Any new measures should add to (and not undermine or distort) investment that could occur without the measures.
2.	If you think extra measures are needed to support renewable generation, which ones should the government prioritise developing and where and when should they be used? What are the issues and risks that should be considered in relation to such measures?
3.	If you don't think further measures are needed now to support new renewable generation, are there any situations which might change your mind? When and why might this be?
4.	Do you think measures could be needed to support new firming/dispatchable capacity (resources reliably available when called on to generate)? If yes, which kind of measures? What needs do you think those measures could meet and why?
5.	Are any measures needed to support storage (such as battery energy storage systems or BESS) during the transition? If yes, what types of measures do you think should be considered and why?
6.	If you answered yes to question 4 or 5 above, should the support be limited to renewable generation and renewable storage technologies only or made available across a range of other technologies? Keep in mind that fossil fuels are generally the cheapest option for firming, though this may change over time as renewable options (particularly batteries) become more efficient and affordable.
7.	If you answered yes to question 6 above, what are the issues and risks with this approach? How could these risks and issues be addressed?
8.	Are any measure(s) needed to support existing or new fossil gas fired peaking generation, so as to help keep consumer prices affordable and support new renewable investment?
9.	If you answered yes to question 8 above, what measures should be considered and why? What are the possible risks and issues with these measures?
10.	If you answered yes to question 8 above, what rules would be needed so that fossil gas generation remains in the electricity market only as long as needed for the transition, as part of phase down of fossil gas?
11.	Are there any issues or potential issues relating to gas supply availability during electricity system transition that you would like to comment on?
12.	Do you agree that specific measures could be needed to support the managed phasedown of existing fossil fuel plants, for security of supply during the transition?

13.	If you answered yes to question 12 above, what measures do you think could be appropriate and why? What conditions do think you should be placed on plant operation? For example, do you have any views on whether there should be a minimum notice period for reductions in plant capacity, and/or for placing older fossil fuel plant in a strategic reserve?
14.	If you answered yes to question 12 above, what are the issues and risks with these measures and how do you think these could be addressed?
15.	What types of commercial arrangements for demand response are you aware of that are working well to support industrial demand response?
16.	What new measures could be developed to encourage large industrial users, distributors and/or retailers to support large-scale flexibility?
17.	Do you have any views on additional mechanisms that could be developed to provide more information and certainty to industry participants?
PART 2: COMPETITIVE MARKETS	
18.	Do you agree that the key competition issue in the electricity market is the prospect of increased market concentration in flexible generation, as the role of fossil fuel generation reduces over time?
19.	Aside from increased market concentration of flexible generation, what other competition issues should be considered and why?
20.	What extra measures should or could be used to know whether the wholesale electricity market reflects workable competition, and if necessary, to identify solutions?
21.	Should structural changes be looked at now to address competition issues, in case they are needed with urgency if conduct measures prove inadequate?
22.	Is there a case for either vertical separation measures (generation from retail) or horizontal market separation measures (amending the geographic footprint of any gentailer) and, if so, what is this?
23.	Are measures needed to improve liquidity in contract markets and/or to limit generator market power being used in retail markets? If yes, what measures do you have in mind, and what would be the costs and benefits?
24.	Should an access pricing regime be looked at more closely to improve retail competition (beyond the flexibility access code proposed by the Market Development Advisory Group or MDAG)?
25.	What extra measures around electricity market competition, if any, do you think the government should explore or develop?
26.	Do you think a single buyer model for the wholesale electricity market should be looked at further? If so, why? If not, why not?
PART 3: NETWORKS FOR THE FUTURE	
27.	Do you consider that the balance of risks between investing too late and too early in electricity transmission may have changed, compared to historically? If so, why?
28.	Are there any additional actions needed to ensure enough focus and investment on maintaining a resilient national grid?

29.	Do you agree we have identified the biggest issues with existing regulation of electricity distribution networks?
30.	Are there pressing issues related to the electricity distribution system where you think new measures should be looked at, aside from those highlighted in this document? How would you prioritise resolving these issues to best enable the energy transition?
31.	Are the issues raised by electricity distributors in terms of how they are regulated real barriers to efficient network investment? Please give reasons for your answer. Is there enough scope to address these issues with the current ways distributors are regulated? If not, what steps would you suggest to address these issues?
32.	Are there other regulatory or practical barriers to efficient network investment by electricity distributors that should be thought about for the future?
33.	What are your views on the connection costs electricity distributors charge for accessing their networks? Are connection costs unnecessarily high and not reflective of underlying costs, or not? If they are, why do you think this is occurring?
34.	If you think there are issues with the cost of connecting to distribution networks, how can government deliver solutions to these issues?
35.	Would applying the pricing principles in Part 6 of the Code to new load connections help with any connection challenges faced by public EV chargers and process heat customers? Are there other approaches that could be better?
36.	Are there any challenges with connecting distributed generation (rather than load customers) to distribution networks?
37.	Are there different cost allocation models addressing first mover disadvantage (when connecting to distribution networks) which the Electricity Authority should explore, potentially in conjunction with the Commerce Commission?
38.	Should the Electricity Authority look at more prescriptive regulation of electricity distributors' pricing? What key things would need to be looked at and included in more prescriptive pricing regulation?
39.	Do current arrangements support enough co-ordination between the Electricity Authority and the Commerce Commission when regulating electricity distributors? If not, what actions do you think should be taken to provide appropriate co-ordination?
40.	Will the existing statutory objectives of the Electricity Authority and Commerce Commission adequately support key objectives for the energy transition?
41.	Should the Electricity Authority and/or the Commerce Commission have explicit objectives relating to emissions reduction targets and plans set out in law? If so, • should those objectives be required to have equal weight to their existing objectives set in law? Why and how might those objectives affect the regulators' activities?
42.	Should the Electricity Authority and/or the Commerce Commission have other new objectives set out in law and, if so, which and why?

43.	Is there a case for central government to direct the Commerce Commission, when dealing with Electricity Distributors and Transpower, to take account of climate change objectives by amending the Commerce Act and/or through a Government Policy Statement (GPS)?
44.	If you answered yes to question 43, please explain why and indicate: • What measures should be used to provide direction to the Commerce Commission and what specific issues should be addressed? • How would investment in electricity networks be impacted by a direction requiring more explicit consideration of climate change objectives? Please provide evidence.
PART 4: RESPONSIVE DEMAND AND SMARTER SYSTEMS	
45.	Would government setting out the future structure of a common digital energy infrastructure (to allow trading of distributed flexibility) support co-ordinated action to increase use of distributed flexibility?
46.	Should central government see how demonstrations and innovation to help inform how trade of flexibility evolves in the New Zealand context, before providing direction to support trade of distributed flexibility? If yes, how else could government support the sector to collaborate and invest in digitalisation now?
47.	Aside from work already underway, are there other areas where government should support collaboration to help grow and develop flexibility markets and improve outcomes? If yes, what areas and actions are a priority?
48.	Could co-funding for procurement of non-network services help address barriers to uptake of non-network solutions (NNS) by electricity distributors?
49.	Would measures to maximise existing distribution network use and provide system reliability (such as dynamic operating envelopes) help in New Zealand? If yes, what actions should be taken to support this?
50.	What do you think of the approaches to smart device standards and cyber security outlined in this document? Are there other issues or options that should be looked at?
51.	Do you think government should provide innovation funding for automated device registration? If not, what would best ensure smart devices are made visible?
52.	Are extra measures needed to grow use of retail tariffs that reward flexibility, so as to support investment in CER and improved consumer choice and affordability?
53.	Should the government consider ways to create more investment certainty for local battery storage? If so, what technology should be looked at for this?
54.	Should further thought be given to making upfront money accessible to all household types, at all income levels, for household battery storage or other types of CER?
55.	Should government think about ways to reduce ‘soft costs’ (like the cost of regulations, sourcing products, and upskilling supplier staff) for installing local battery storage with solar and other forms of CER/DER storage? If so, what technology should be looked at?
56.	Is a regulatory review of critical data availability needed? If so, what issues should be looked at in the review?

PART 5: WHOLE-OF-SYSTEM CONSIDERATIONS	
57.	What measures do you consider the government should prioritise to support the transition?
58.	Are there gaps in terms of information co-ordination or direction for decision-making as we transition towards an expanded and more highly renewable electricity system and meeting our emissions goals? Please provide examples of what you'd like to see in this area.
59.	Are there significant advantages in adopting a REZ model, or a central planning model (like the NSW EnergyCo), to coordinate electricity transmission investment in New Zealand? Would a REZ model for local electricity distribution be an effective means of addressing first mover disadvantage with connecting to electricity distribution networks?
60.	Should MBIE regularly publish opportunities for generation investment to enable informed market decision-making?
61.	How should the government balance the aims of sustainability, reliability and affordability as we transition to a renewable electricity system?
62.	To what extent should wholesale, transmission, distribution or retail electricity pricing be influenced by objectives beyond the (affordability-related) efficiencies achieved by cost-reflective pricing, such as sustainability, or equity?
63.	Are the current objectives for the system's regulators set in law (generally focusing on economic efficiency) appropriate, or should these also include more focussed objectives of equity and/or affordability?